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Decision 91-10-039 October 23, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation on the Commission's own motion to implement the Biennial Resource Plan Update following the California Energy Commission's Seventh Electricity Report.	ORIGINAL I.89-07-004 (Filed July 6, 1989)

(See Attachment 5 in Decision 90-03-060 for appearances.)

Additional Appearances

Marron, Reed & Sheehy, by Emilio E. Varanini III, for Texaco Syngas Inc.; Peter Ouborg, Attorney at Law, for Pacific Gas and Electric Company; David M. Abday, for Amoco Production Company; Randall S. Goldstein, for GWF Power Systems; Adrian T. Hudson, for California Gas Producers Association; David R. Stevenson, for Chevron U.S.A. Inc.; William Meckling, for Recon Research Corporation; and Daniel Kirshner, for Environmental Defense Fund; interested parties.

OPINION ESTABLISHING AN INTERIM METHOD FOR CALCULATING AVOIDED ENERGY COSTS

1. Summary

In Phase III of this proceeding, we will consider revisions to the methodology used for calculating avoided cost payments from electric utilities to power producers from whom they are required to buy electricity (qualifying facilities, or QFs). In this decision, we adopt an interim modification to the existing avoided energy cost methodology prompted by changes in the way electric utilities procure natural gas.

2. Background

On August 1, 1991, fundamental changes took place in the way that gas utilities serve their utility electric generation (UEG) customers (See Decision (D.) 90-09-089). One change resulting from that decision is that the gas utilities no longer have a noncore portfolio and, therefore, no longer publish a noncore portfolio price. This change is important to electric utilities and the power producers from whom they are required to buy electricity pursuant to the federal Public Utility Regulatory Policies Act of 1978. The Commission requires that each electric utility post quarterly energy price offers intended to represent the utility's own avoided costs for the coming quarter.

In a series of decisions beginning with D.91109, the Commission established a methodology for the electric utilities to follow in making that posting. When the fuel on the margin is natural gas, the utility must apply to the calculation its weighted average cost of gas (WACOG). If it includes noncore gas in its UEG supplies, then the utility must use the noncore WACOG for that portion.

Prior to August 1, 1991, the cost of natural gas was fairly readily determined. For example, Southern California Edison Company (SCE) based the cost of natural gas on gas volumes, transmission rates, and charges contained in Commission decisions and advice letters filed by Southern California Gas Company. QFs or other interested parties were able to refer to the gas portfolio prices and transportation tariffs to do their own gas-cost calculation. However, since the gas utilities ceased publishing a noncore portfolio price as of August 1, 1991, a new means must be adopted for calculating avoided energy costs.[1]

In Phase III of this proceeding, we plan to consider a new pricing methodology. However, we must adopt an approach to be used by the electric utilities in the interim.

Pursuant to an Assigned Commissioner's Ruling (February 15, 1991), the Commission Advisory and Compliance Division (CACD) conducted a workshop on March 14, 1991, to seek consensus on a new interim gas-price benchmark. CACD was directed to file a workshop report summarizing the parties' proposals and reporting any agreement reached at the workshop. In the absence of agreement, CACD was directed to include, in its report, its own recommended interim approach. By letter dated March 18, 1991, CACD representatives reported the workshop results to the administrative law judge then assigned to the matter. The letter indicated that agreement had not been reached. On March 22, 1991, the assigned commissioner issued a ruling calling for a second workshop (held April 8, 1991). The purpose of the second workshop was to further encourage agreement on an interim benchmark formula. Despite the concerted efforts of several parties, agreement did not result. Parties were allowed to file post-workshop comments. On April 30, 1991, CACD released its workshop report, which included its recommended interim approach.

1 An exception to this is SDG&E because in D.90-09-089, we permitted SDG&E to continue to supply gas to its noncore customers, including its UEG customers. As a result, SDG&E continues to sell UEG gas at a tariffed rate, which provides a basis for computing avoided cost in the same manner as SDG&E has done prior to our gas restructuring.

The CACD recommendation drew upon the proposals of the parties but did not resemble any other specific proposal. Parties were then provided with a formal opportunity to comment on the CACD proposal. Concurrent comments were filed on June 21, 1991.

In their comments, several parties objected to the adoption of the CACD proposal and expressed a preference for hearings to consider the merits of alternative approaches and to resolve questions of implementation raised by the CACD proposal, but acknowledged that there was not adequate time to hold hearings and issue a decision prior to August 1, 1991. SCE went a step further and asked that hearings be held, although the adopted solution is intended to be interim in nature. SCE offered several issues that it argued should be resolved in evidentiary hearings.

In a ruling dated July 1, 1991, the assigned commissioner set hearings on the proposed interim methodology. The hearings were held commencing July 29, 1991. Since we knew that a decision based on the those hearings could not be issued before August 1, 1991, we issued D.91-07-052 in which we directed the electric utilities to use the existing methodology for the quarter beginning August 1, 1991. Since there was no noncore WACOG in effect on August 1, 1991, we instructed the utilities to apply the noncore weighted average cost rate in effect on July 31, 1991 for this one-time calculation.

Hearings on the interim replacement for the noncore WACOG were held July 29, 30, and 31, 1991, and August 8, 1991. Testimony was offered by SCE, Cogenerators of Southern California (CSC), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), the Division of Ratepayer Advocates (DRA), the Geothermal Resources Association and the Independent Energy Producers Association (GRA/IEP), and the California Cogeneration Council (CCC). The proposed decision was mailed on September 23, 1991, and various parties filed comments. This decision has been modified to reflect the comments where appropriate.

3. The Proposals

With the exception of SDG&E, the participants in these hearings support one of two different methods for replacing the noncore WACOG in calculating avoided energy costs on an interim basis. The QF parties (CSC, CCC, and GRA/IEP) support the CACD recommendation that an index be established, relying on public predictions of spot-market gas prices for gas to be purchased from certain relevant production basins. SCE, PG&E, and DRA support the use of recorded UEG gas costs for a given month to calculate avoided energy cost payments two or three months later. All parties agree that the quarterly filing process, under which a preliminary posting was made 30 days prior to the beginning of each quarter, should be scrapped. Instead, all parties ask to have new energy prices posted monthly.

The formula used to calculate avoided energy costs, prior to August 1, 1991, took into account the percentage of UEG gas that was purchased from the core portfolio as opposed to the noncore portfolio. It has generally been assumed that the portion of the avoided energy costs reflecting core portfolio purchases would continue to be calculated as it has been before. SDG&E intends to purchase all of its UEG gas from its core portfolio and has thus not expressed an opinion as to the appropriate replacement for the noncore WACOG. SDG&E has, however, expressed its support for changing from a quarterly to a monthly posting process.

3.1 CACD

CACD describes its proposal as follows:

> "CACD believes the price which represents the non-core subscription portion of gas should include a commodity price and an interstate transportation rate. This price will represent the California border price for volumes that are not core subscription just as the core WACOG represents a California border price for core subscription volumes. The two portions, core subscription and noncore subscription, should then be adjusted to represent intrastate tariffs and UEG service level elections. This

will best represent avoided gas cost on an interim basis....

"The index we recommend for the noncore subscription portion is adapted from those presented by the QF coalition at the second workshop. CACD recommends that the Commission adopt a consistent method for all utilities which weights the prices of different supply basins accessed by the utilities then adds on interstate transportation costs to arrive at the California border price.

"CACD recommends that each individual basin cost be the average of the price recorded by Natural Gas Week, Natural Gas Intelligence, and Inside FERC for the first nonholiday day each month. The utilities should make their postings on the first Monday of each month. If these two days coincide, the utilities should make their avoided costs postings on the second Monday of the month.

"CACD recommends that the utilities initially weigh the supply basin prices according to a forecast based on historical throughput on the various pipelines each utility has access to. This information can be derived from utilities' most recent Annual Cost Allocation Proceeding/ Biennial Cost Allocation Proceeding (ACAP/BCAP) proceedings. CACD recommends that the firm transportation rate be used as the adjustment to supply basin indices.

"As additional pipelines come on-line or utility procurement strategies change significantly, CACD recommends that the utilities consult with interested parties regarding the appropriate index and weighting to use to represent the noncore price. A reopener is unnecessary to accommodate these changes.

"CACD recommends that the protest period remain the same with only the potential for upward adjustment of posted prices. The prefiling requirement would be removed.

"CACD recommends that the Commission require the utilities to submit an annual report which indicates the monthly gas price under the index approach, recorded approach, and the core WACOG. This document will allow comparison of the different approaches and should greatly assist the administrative law judge in Phase III of this proceeding in assessing the methods we [considered in the] workshops.

"The interim approach the Commission chooses to adopt should in no way be considered an endorsement of that approach in Phase III. CACD agrees with PG&E that '...the Commission should adopt a provision that requires revisiting of the adopted approach in two years...' if the Phase III proceeding has not yet begun."

3.2 SCE

SCE proposes a new method for calculating avoided energy costs, relying on recorded fuel costs incurred by SCE in generating electricity from its oil/gas generating units. SCE argues that these units are "on the margin" and therefore are used to respond to changes in electricity requirements. SCE argues that by including both recorded oil and gas costs in the calculation, the avoided cost energy payment calculation is simplified in that SCE would not have to forecast its oil and gas fuel mixed. The costs incurred by SCE to generate electricity would be used to determine the payments to QFs for electric generation that would occur two or three months later.

In its testimony, SCE stated that it would calculate its recorded fuel costs by deriving four values from its monthly Fuel Commitment Statement:

"1. The amount of gas burned on the Edison system that is used directly for generation in the oil and gas system;

"2. The total commodity cost of that gas;

"3. The amount of oil burned on the Edison system that is used for generation in the oil and gas system; and

"4. The total cost of that oil."

The amount of gas used for generation would be equal to the total gas burned, less gas burned for other purposes such as igniter fuel for coal plants and gas used at isolated generating units. The total commodity cost of gas used directly for generation would be derived from the data in the Fuel Commitment Statement by subtracting, from the total gas cost, all gas cost components that are not commodity cost-related. For example, demand charges, customer charges, and transportation charges would all be subtracted. The oil price would be based on the recorded cost of fuel burned. The avoided fuel cost would be the sum of the recorded gas commodity costs (including associated transportation costs to the California border) and oil costs, divided by total oil and gas British Thermal Units (Btus).

SCE proposes that certain costs be included or excluded from the calculation based on whether or not they are avoidable as a result of QF generation. SCE argues that costs can be categorized as follows:

Included Items:

Cost of oil purchased, including taxes and transportation
Adjustments to the cost of oil
Commodity cost of gas purchased, all suppliers
Adjustments to the cost of gas
Interstate gas transportation charges
Charges associated with the G-STOR program
Gas refunds
CPUC-imposed interstate volumetric surcharges imposed on all noncore customers

Excluded Items:

Cost of other fossil fuels used by combustion turbines and diesel generators
Gas demand and transportation charges from PG&E and Long Beach
Gas for Mohave and Four Corners
Charges associated with the G-STAQ program

Southern California Gas Company use-or-pay and take-or-pay charges or penalties, such as under the August 1, 1991 service level structure

3.3 PG&E

PG&E offers an approach which appears similar to SCE's recorded cost methodology. PG&E calls its version an "actual cost" approach, and describes it as follows:

> "The actual UEG self-procured gas costs will be calculated based on the actual payments made to suppliers plus any costs to transport the gas to the California border. The weighted average cost per MMBtu (million Btus) will then be derived by dividing the total cost by the total MMBtu received at the California border.
>
> "UEG gas costs will be determined the month following the date of the actual purchases (the 'invoice verification month'), and will reflect the UEG's actual out-of-pocket costs. UEG self-procured gas costs for purposes of computing QF avoided cost payments will be calculated by the last working day of the invoice verification month, i.e. more-or-less 30 days following the UEG gas consumption month. For example, the August gas costs will be finalized by September 30, and will be available to calculate the avoided cost to be paid to QFs for energy generated during October...
>
> "Any adjustments that occur after the invoice verification month will be infrequent and will not likely be significant. Such adjustments could be in either direction and could occur for limited reasons such as errors either in the measurement and/or allocation of gas or changes in the volumes of gas resulting from the prospective imbalance trading program as provided by the CPUC.
>
> "In addition, adjustments after the invoice verification month will be confined to the month in which they occur. Using August self-procured gas costs as an example again, any updating after September 30 would be applied to the month in which the update correction was

> identified and verified. Specifically, if during October an adjustment was identified for a particular supplier for gas purchased during August, then the adjustment would be included as a part of the October gas costs."

3.4 Other Parties

DRA supports the utility proposals. The QF parties support CACD's proposal, although some QFs would propose minor modifications. GRA/IEP recommends that the utilities routinely make their avoided cost postings on the second Monday of each month and that the gas price reflected in that posting be in effect until the second Monday of the subsequent month. CCC proposes other modifications, which will be addressed below.

4. Discussion

We have two interim approaches before us. On balance, we find that it is more appropriate to adopt CACD's proposed index approach. For reasons that will be discussed below, we find that the concerns that have been voiced about the index approach can be adequately addressed through modifications to CACD's proposal to allow us to apply the index approach on an interim basis.

In Phase III of this proceeding, we will reexamine the process for determining avoided energy costs. Our goal, in this decision, is to adopt an interim solution to the dilemma caused by the elimination of the noncore portfolio while retaining the character of the price-setting approach currently in effect.

The choice offered here is very much the same one faced by the Commission when it first approved the utilities' standard offer contracts for QFs: a choice between prices based on forecasted fuel costs and prices based on prior period fuel costs. Here is how the Commission explained its choice at the time:

> "Many of the parties were concerned with the fuel costs used in determining the avoided energy costs. Concerns were raised whether forecasted fuel prices, prior period fuel

prices, or retrospective prices should be used and how the determination of the marginal fuel at any particular time would be made:

"Currently, the energy prices are set by utilities at the beginning of the quarter and QFs can anticipate that payments will be based on those prices throughout the quarter...Adjustments are not made at the end of the quarter to reflect actual conditions during that quarter. This procedure gives QFs a clear and predictable price upon which they can base operations for future periods, but it also results in a relatively less accurate determination of the short-run operating costs than if prices were established retrospectively with fuller knowledge of what actually occurred. Some suggestions were made in the proceeding that the prices be adjusted at the end of the quarter to reflect actual prices paid during the quarter for fuel. Payments to QFs would be retroactively adjusted at the end of the quarter to coincide with actual fuel prices paid during the quarter.

"We conclude that the current procedure of prospectively establishing prices is preferable. This procedure gives QFs a clear price signal from which to determine its operations for the upcoming quarter. In reaching these prospective determinations, we will attempt as accurately as possible, to project the fuel mix which will occur in the future quarter. Any variations in the projected price should likely be as high as they would be low, and deviations should cancel out over time. Retrospective adjustment would undoubtedly create significant controversy, be cumbersome and destabilize the market for small power producers." (D.82-12-120, 10 CPUC 2d 553, pp. 620-621.)

In the current instance as well, the utilities propose the use of historical costs, instead of forecasts, to form the basis of energy payments to QFs. In its prepared testimony (Exhibit W5, pp. 9 and 10), PG&E acknowledges that the index approach is "guaranteed" to correspond well with the noncore WACOG, but questions whether mimicking the noncore WACOG is the most accurate way to calculate avoided costs. If we want the avoided energy costs payments to be precisely equal to UEG gas costs, then a recorded approach should be used. However, as discussed below, we are not convinced that the index approach as modified will produce significant inaccuracies. For now, we choose to adhere to the principles of D.82-12-120 by sacrificing some possible precision in exchange for a more predictable, less controversial calculation. In an effort to make the energy prices more accurate over time, the utilities would ensure that actual fuel costs would not have an impact on avoided cost payments until some months after the costs were incurred, require cumbersome verification procedures to assure the accuracy of utility calculations, encourage repeated controversy surrounding the calculations, and subject QF payments to frequent tinkering and adjustment as the recorded cost data is refined. We need not make such fundamental changes to the calculation of avoided energy costs as part of an interim solution. We had best not take on the potential consequences of an historic cost approach without the more careful analysis we hope to give this issue in Phase III.

There are numerous issues raised by parties concerning the implementation of an interim methodology, many of which also reflect on the merits of adopting the index approach. We will discuss each issue below.

4.1 Frequency and Timing of Posting

Currently, the utilities are required to post new energy prices each quarter. Preliminary postings are released a month in advance, giving QFs a month to file protests if they disagree with the utility calculations. All parties now request that the quarterly filing process be replaced with a monthly filing. The preliminary posting requirement would be eliminated and QFs would still have 30 days in which to file a protest. Although this represents a fundamental change in the posting process, it is a change which everyone wants. Although the QFs will forgo the stability and longer planning horizon provided when the same rates are in effect for three months, all parties gain the advantage of allowing avoided cost energy prices to be more responsive to changes in gas prices. We will adopt this change.

Since the published forecasts of monthly gas costs may not consistently be available prior to the first of the month, it is possible that the utilities may not always be able to post new energy prices on the first of the month. CACD recommends that new prices be posted on the first Monday of each month. SCE proposes that the prices be posted on the Thursday following the first Monday, effective the first of the month. CSC recommends posting on the Thursday following the first Monday, effective on the second Monday. GRA/IEP suggest posting on the second Monday, effective the second Monday. We will adopt the GRA/IEP approach because it is the simplest (prices effective the day they are posted), increases the likelihood that the published forecasts will be available on time, and provides for prices that will only be applied prospectively. If a published index is not available for timely use, the utility should rely on those indices that are available.

Under this approach, the first new posting would not become effective until the first time a second Monday of the month occurs after this order is signed. Normally, the avoided costs posted on August 1, 1991 would remain in effect until November 1, 1991. To bridge the gap, the current avoided costs will remain in force until the first postings in compliance with this order become effective.

4.2 Basin Weights

The cost of gas differs depending on its source. In order to accurately forecast the UEG cost of gas, it is necessary to know the relative amounts of gas that will be purchased from various basins.

The challenge of producing accurate forecasts of basin weightings has been raised by SCE, PG&E, and DRA as a criticism of the index approach. The utilities and DRA point out that an inaccurate forecast of basin weightings could add several million dollars to ratepayer costs. CACD proposes that the basin weightings be fixed, based on historical throughput information derived from ACAP/BCAP proceedings. However, the utilities and DRA argue, basin waitings may fluctuate throughout the year depending on availability and price. The utilities also argue that fixed basin weighting assumptions will provide an upward bias to QF payments, since the utilities are likely to adjust their basin takes in order to lower the cost of gas.

One way to reduce inaccuracies resulting from the use of fixed basin weightings would be for the utilities to forecast basin weightings each month. SCE, DRA, and PG&E argue that a major attraction of the index approach (the objective nature of the calculation) is undermined if the utilities must predict the basin weighting likely to apply in a given month. Although a monthly estimate of basin weightings by the utilities adds a layer of judgment to the process, it is the best way to increase the accuracy of the monthly energy cost forecast. To minimize controversy resulting from this exercise of judgment, we will direct the utilities to provide specific information about the basin weightings at the time each posting is made.

4.3 Canadian Supplies

As proposed by CACD, monthly gas cost forecasts would be derived from certain published indices that predict spot-market prices for gas to be purchased from basins in the Southwest. SCE argues that the use of these published indices may be insufficient, since the UEG customers may procure gas from Canada as well. If Canadian sources of gas will be used in a given month, the utility should be able to include a projection of amounts of Canadian gas to be purchased that month. The same publications relied on for

Southwest basin prices could be used for Canadian prices. Several parties have questioned the existence of a publication offering a reliable forecast of Canadian prices. We intend to use the best forecasts available. If all parties active in this phase of the proceeding can agree on other sources of Canadian price forecasts upon which to rely, we hereby approve the use of those sources for Canadian spot-market price forecasting.

4.4 Long-term Contracts

SCE's witness Curtis Kebler testified that his company has solicited bids for multi-month gas supply contracts, has received bids that offer discounts below prices reflected in the spot-market index, and intends to enter into such a contract. The utilities and DRA argue that a rigid reliance on spot-market prices would bias the prices to the detriment of ratepayers. The QFs argue that long-term contracts do not always result in lower costs and that they are willing to take the risk that the spot-market prices may be lower than actual UEG takes pursuant to long-term contracts. SCE responds that in light of the current abundance of gas, suppliers should be willing to make firm supply commitments at prices below the spot market.

It is not obvious that, over the course of time, spot-market prices would remain higher than prices offered under firm contracts. If supplies remain abundant, as SCE suggests, then suppliers should be motivated to reduce spot prices to move more gas. If supplies become constrained, then long-term contracts would become more costly. Further, Kebler testified about solicitations for bids covering prices for some unspecified number of months. His testimony does not suggest that SCE is seeking long-term price security or that it would be purchasing significant volumes of gas under such arrangements. We are not convinced that long-term contracts are likely to have a significant impact on UEG gas costs in the short term. Thus, we will not require a modification of the CACD proposal concerning long-term contracts.

If history proves us wrong, then this issue can be reconsidered in Phase III.

4.5 Transportation Rates

To accurately mimic the current avoided cost methodology, the interim gas benchmark should reflect both interstate and intrastate rates for transportation. The gas utilities (LDCs) currently hold firm rights over the interstate pipelines. Under the Commission's new service level program, gas customers can select the level of service which they wish to obtain on the intrastate system. The rates which they pay to the LDC reflect interstate transportation as well as intrastate rates as a bundled rate. Therefore the service level election by the UEG effectively determines the full transportation rate for gas transported under the LDC programs. Since Southern California Gas Company (SoCalGas) and PG&E have held the open seasons for their programs, the UEG's service level elections are already known.

For gas transported over the interruptible queue, it would be appropriate to use the interruptible Federal Energy Regulatory Commission (FERC) tariffed rate for interstate transportation portion and the intrastate default rate for the intrastate portion.

Parties have raised the issue of how to deal with Transwestern's discounted interruptible rates. DRA has proposed that as a proxy for gas transported over the Transwestern system that the FERC interruptible tariff for El Paso from the Permian Basin be used. Parties were generally supportive of this approach. Since it is expected that Transwestern's discounting will make the rates of the two companies virtually the same, this approach appears reasonable and we will adopt it.

4.6 New Pipelines

SCE has argued that as new pipelines come into service, UEG customers may be able to gain access to new supply basins. SCE suggests that if this occurs, it may be necessary to reconsider any adopted indexing approach. DRA argues that it will be necessary to monitor activities concerning new pipelines and capacity brokering as they may affect the index process and reexamine the index formula if inaccuracies occur. CCC argues that UEG customers are unlikely to be purchasing noncore supplies on new pipelines, since they own no rights to capacity on new lines.

At this point, any impact on UEG gas costs as a result of the availability of new pipelines is speculative. Since the method adopted in this decision is an interim approach, we can defer consideration of new pipelines until better information is available.

4.7 Comparison Report

In its workshop report, CACD recommended that the Commission require each utility to submit an annual report which indicates the monthly gas price under the index approach, recorded approach, and the core WACOG. The purpose of this document would be to facilitate comparison of the different approaches in Phase III. SCE offers to file such reports every six months and asks that this portion of the proceeding be reopened if a report shows differences between the index and recorded approaches. DRA proposes that this phase be automatically reopened if the index is found to deviate from recorded costs by 10% over a 6-month period or 5% over a year. The QFs have not supported automatic reconsideration of the index methodology.

We will direct the utilities to file such reports on an annual basis. The utility testimony as to the lag between the time when gas's purchase and the time when the utility can accurately calculate its costs suggests that a six-month report may not produce an accurate comparison. A comparison of the index approach with historical noncore WACOG figures suggests that, at a minimum, the index approach accurately tracks the noncore WACOG rate which we are striving to replace. In addition, it is our intention to adhere to this interim process until a broader examination of pricing methodologies can occur in Phase III. Thus, we will not prescribe a procedure for automatically reopening this phase of the proceeding. If the utility reports suggest large differences in the results depending on which method is used, we can reopen this process on our own motions by asking parties to file comments on the significance of differences. We anticipate that meaningful comment by the parties would need to be preceeded by a careful examination of the calculations offered by the utility.

5. Conclusion

For the purpose of calculating avoided energy costs, we will adopt CACD's recommended index approach to forecasting the cost of gas purchased by UEG customers from sources other than the core portfolio. This approval is subject to the modifications described above and is intended to serve as an interim cost calculation mechanism pending related considerations in Phase III of this proceeding.

Findings of Fact

1. The Commission requires that each electric utility post quarterly energy price offers for QFs intended to represent the utility's own avoided costs for the coming quarter.

2. When the fuel on the margin is natural gas, the utility must apply to the calculation its WACOG; if it includes noncore gas in its UEG supplies, then the utility must use the noncore WACOG for that portion.

3. Since the gas utilities ceased publishing a noncore portfolio price as of August 1, 1991, a new means must be adopted for calculating avoided energy costs.

4. In Phase III of this proceeding, we plan to examine new pricing methodologies.

5. On April 30, 1991, CACD released a workshop report, which included its recommended interim approach for determining UEG noncore gas costs.

6. SCE proposes a new method for calculating avoided energy costs, relying on recorded fuel costs incurred by SCE in generating electricity from its oil/gas generating units.

7. PG&E offers an approach which appears similar to SCE's recorded cost methodology.

8. DRA supports the utility proposals.

9. The QF parties support CACD's proposal, although some QFs would propose minor modifications.

10. The utilities would ensure that actual fuel costs would not have an impact on avoided cost payments until some months after the costs were incurred.

11. The utilities' proposal would require cumbersome verification procedures to assure the accuracy of utility calculations.

12. The utilities' proposal would encourage repeated controversy surrounding the calculations, and subject QF payments to frequent tinkering and adjustment as the recorded cost data is refined.

13. By changing from quarterly to monthly filings, all parties gain the advantage of allowing avoided cost energy prices to be more responsive to changes in gas prices.

14. Posting on the second Monday, effective the second Monday is the simplest (prices effective the day they are posted), increases the likelihood that the published forecasts will be available on time, and provides for prices that will only be applied prospectively.

15. Although a monthly estimate of basin weightings by the utilities adds a layer of judgment to the process, it is the best way to increase the accuracy of the monthly energy cost forecast.

16. If Canadian sources of gas will be used in a given month, the utility should be able to include a projection of amounts of Canadian gas to be purchased that month.

17. Several parties have questioned the existence of a publication offering a reliable forecast of Canadian prices.

18. It is not obvious that, over the course of time, spot-market prices would remain higher than prices offered under firm contracts.

19. We are not convinced that long-term contracts are likely to have a significant impact on UEG gas costs in the short term.

20. The service level election by the UEG effectively determines the full transportation rate for gas transported under the LDC programs.

21. Since SoCalGas and PG&E have held the open seasons for their programs, the UEG's service level elections are already known.

22. It is expected that Transwestern's discounting will make its interruptible rates virtually the same as those of El Paso.

23. At this point, any impact on UEG gas costs as a result of the availability of new pipelines is speculative.

24. It is our intention to adhere to this interim process until a broader examination of pricing methodologies can occur in Phase III.

25. There will be a gap of time between November 1, 1991 and the date on which postings in compliance with this order would first become effective.

Conclusions of Law

1. The concerns that have been voiced about the index approach can be adequately addressed through modifications to CACD's proposal to allow us to apply the index approach on an interim basis.

2. We are not convinced that the index approach as modified will produce significant inaccuracies.

3. The utilities should be required to provide specific information about the basin weightings at the time each posting is made.

4. If all parties active in this phase of the proceeding can agree on other sources of Canadian price forecast upon which to rely, we should approve the use of those sources for Canadian spot-market price forecasting.

5. Unless there is agreement on other sources of Canadian gas prices, utilities should use those publications that are the source of gas prices from Southwest basins and that contain Canadian gas prices.

6. The indexing approach proposed by CACD, as modified herein, is an appropriate interim replacement for the noncore WACOG and should be adopted.

7. This order should be effective immediately to enable the electric utilities to post avoided energy cost offers consistent with this order in November 1991.

8. The current avoided cost prices should remain in force until the first postings in compliance with this order become effective.

9. Beginning January 31, 1993 and annually thereafter, each electric utility procuring gas outside of the core portfolio shall submit a report comparing the gas prices calculated using the index approach adopted in this decision with recorded gas costs, and if applicable, the core WACOG.

ORDER

IT IS ORDERED that:

1. The index approach for calculating the noncore gas component of avoided energy costs shall be adopted, as modified in this decision.

2. Beginning in November, 1991, the electric utilities shall post avoided cost price offers monthly on the second Monday of each month, to become effective on the second Monday of the month and remain in force until the effective date of the next posting.

3. Monthly posting shall include the following information to help explain the forecast:

a. The most current UEG nominations under the appropriate gas utility's service level program;

b. For gas purchased outside of core subscription, a forecast of how UEG requirements will be met, specifying the basin and volumes they expect to flow from that basin.

c. In each instance, the pipeline utilized.

d. Documentation of the UEG's actual takes in the prior month.

4. The current avoided cost price offers shall remain in force until the first postings in compliance with this order becomes effective.

This order is effective today.

Dated October 23, 1991, at San Francisco, California.

PATRICIA M. ECKERT
President
JOHN B. OHANIAN
DANIEL Wm. FESSLER
NORMAN D. SHUMWAY
Commissioners

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY

Neal J. Shulman

NEAL J. SHULMAN, Executive Director